Accelerating Residential PV Expansion: Supply Analysis for Competitive Electricity Markets

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Abstract

Photovoltaic (PV) technology is now sufficiently advanced that market support mechanisms such as net metering plus a renewable portfolio standard (RPS) could induce rapid PV market growth in grid-connected applications. With such support mechanisms, markets would be sufficiently large that manufacturers could profitably build and operate 100 MW_p/year PV module factories, and electricity costs for residential rooftop PV systems would compare favorably with residential electricity prices in certain areas (e.g., California and the greater New York region in the U.S.). This prospect is illustrated by economic and market analyses for one promising technology (amorphous silicon thin-film PV) from the perspectives of both module manufacturers and buyers of new homes with rooftop PV systems. With public policies that reflect the distributed and environmental benefits offered by PV—and that can sustain domestic PV market demand growth at three times the historical growth rate for a period of the order of two decades—PV could provide 3% of total U.S. electricity supply by 2025.

Keywords

photovoltaics, net metering, renewable portfolio standard

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Introduction

Photovoltaic (PV) technology has reached a crossroads at which appropriate public policies could open up large-scale fully commercial markets for distributed grid-connected power. As a result of advances from R&D [e.g., the US federal PV R&D investment totaled $2.4 billion (1999$), 1974-1999] and early market experience, PV module costs have declined by more than an order of magnitude since 1976 (see Figure 1). Already PV is the least-costly means of providing electricity to households with modest demand levels at sites remote from electric grids, including rural households in developing countries (Cabraal et al., 1996). PV systems for grid-connected applications are not yet competitive, but installed costs for grid-connected residential rooftop applications have fallen from $17 per W_{ac} in 1984, to $9 per W_{ac} in 1992 and $6 per W_{ac} in 1996 (PCAST Energy R&D Panel, 1997). Several PV vendors have indicated that installed costs for residential systems could reach $3 per W_{ac} before 2005 (Forest and Braun, 1997; Lawry, 1996). At this level, PV would theoretically be cost-effective for 10 million US homes (40,000 MW_p at 4 kW_p each) with no support mechanisms other than home mortgage financing and net metering—a policy that allows customers to run their electric meters backward, delivering excess electricity to the grid for credit at retail rates during periods when PV generation exceeds on-site demand (Marnay et al., 1997).

Given that current energy prices do not reflect environmental costs and that firms introducing clean energy technologies suffer from knowledge spillovers to competitors, public-sector support is warranted to help commercialize PV as well as other renewable energy technologies with substantial long-term potential to displace fossil fuels (PCAST Energy R&D Panel, 1997; PCAST ICERD[3] Panel, 1999; Duke and Kammen, 1999). Commercialization incentives should aim to buy down costs for a *portfolio of emerging technologies* to the point that some will be able to compete against conventional electricity supplies without further subsidy (PCAST ICERD[3] Panel, 1999). Such support should be provided using competitive instruments that are consistent with the global trend towards competitive electricity markets.

One such mechanism requires each utility or deregulated electricity service provider to include in its portfolio of electricity supplies a small but growing fraction of renewable energy. These companies could either produce this renewable electricity themselves or purchase renewable energy credits that are sold in a credit trading market. The program would be phased out after a transitional period during which new renewable energy industries are launched in the market. This mechanism, called the Renewable Portfolio Standard (RPS) in the United States and typically a Green Certificate Market (GCM) in Europe, is becoming the approach of choice for helping launch renewables in competitive electricity markets (Berry and Jaccard, 2001). The Netherlands, Italy, Denmark, and Australia have all introduced RPS or GCM initiatives. Moreover, Belgium is close to developing an RPS/GCM, and in the UK discussions are underway aimed at replacing the Renewables Non-Fossil Fuel Obligation [the mechanism that has been used to advance renewables in the market since 1990 (Mitchell, 2000)] with an RPS/GCM having a 10% renewable requirement by 2010.

In the United States, eight states have implemented an RPS in conjunction with broader electricity market restructuring initiatives.[4] At the federal level, a number of bills have been introduced in Congress with provisions for a federal RPS, including the Comprehensive Electricity Competition Act proposed by the Clinton Administration.[5] The RPS in this bill requires that each retail electricity supplier generate or purchase credits equivalent to 7.5% of the electricity it sells from renewable sources other than hydropower by 2010. The mandate continues at this level until 2015, at which time it ceases completely.

Under a competitive process such as an RPS the cost of a buy down should be less than for any administrative process. Figure 2 presents data relating to an example of the latter—price per unit of output for 351 individual PV systems subsidized under a recent California Energy Commission buy-down program. The four-fold range in unit price suggests that the program failed to leverage limited subsidy funds effectively; under a competitive process unit prices of subsidized systems would be clustered near the lower end of this price range.[6]

At the same time, competitive mechanisms discriminate against PV technologies, for which the near-term cost reduction potential is excellent but whose current electricity costs are high relative to mature renewable technologies such as wind energy. This problem could be overcome by combining an RPS[7] with net metering—a complementary policy that recognizes that electricity generated near users is worth more than central station power. [8]

This paper describes the potential near-term impacts of an RPS plus net metering (with no cap) aimed at capturing over a decade (e.g., 2007-2016) about 1/10 of the theoretical 40,000 MW_p residential PV market indicated above for the United States—equivalent to installing PV on about one million residential rooftops. If this accelerated PV development scenario could be realized, PV would satisfy 0.4% of residential electricity demand or 0.15% of total U.S. electricity demand in 2016. While this would be a trivial contribution to national energy

[4] See State Regulatory Programs & Policies Table, Database of State Incentives for Renewable Energy, at www-solar.mck.ncsu.edu and also www.ucsusa.org for a more recent update.

[5] http://hom.doe.gov/policy/ceca.htm.

[6] The higher cost systems shown in Figure 2 suggest that some consumers are willing to pay a large premium to obtain residential PV. Electricity service providers may also be willing to pay homeowners a premium for the right to purchase and resell their PV power as part of a green electricity blend. The ultimate magnitude of green demand remains uncertain, however, especially given that conventional electricity users can "free ride" on the environmental benefits provided by green power purchasers (Rader and Norgaard, 1996).

[7] In the near term, emerging state-level RPS requirements are expected to induce bilateral purchase agreements between a handful of parties (e.g., utilities contracting with independent landfill methane and wind power producers). There are administrative challenges in making the RPS relevant for thousands of residential PV systems without excessive transaction costs. Duke et al. (in progress) proposes a range of possible strategies to ensure that system installers and/or owners are able to efficiently obtain compensation under an RPS.

[8] In the United States, some 30 states have implemented net metering initiatives to encourage use of PV technologies--13 of which specify caps on the amount of PV capacity eligible for net metering. www-solar.mck.ncsu.edu.

requirements, it would put PV on a path toward realizing its long-term potential. Moreover, under this scenario, US domestic PV sales would have to grow for a decade some 38% per year (three times the historical growth rate, 1988-1998) and would reach by 2016 a level more than 60 times the 1998 level of 15 MW_p/yr.[9]

The analysis is a bottom-up assessment of prospects for making residential net-metered PV economically attractive to both module manufacturers and homeowners based on scaled-up production. Results are presented of detailed cost estimates for PV module production at the 100 MW_p/yr scale for alternative amorphous silicon (a-Si:H) technologies, along with installation costs and lifecycle electricity generating costs for 4 kW_p PV rooftop systems in new U.S. residential housing.

Cost-Cutting Opportunities

This assessment takes into account opportunities for cost reduction for PV systems as a result of competition, economies of scale, marginal technological improvement, and learning-by-doing.

Potential *cost cutting via competition* is taken into account by focusing on two amorphous silicon (a-Si:H) thin-film technologies—one based on rigid modules (glass substrate, as being developed by BP Solarex) and the other based on flexible modules (thin-rolled stainless-steel substrate, as being developed by United Solar Systems Corporation, USSC).[10] Thin-film systems are expected to be among the least costly PV technologies during the next decade (EPRI/OUT, 1997; BPA, 1999), and a-Si:H is a thin-film option close to being ready for large-scale deployment.

Potential *cost cutting via scale economies* is explored by focusing on PV modules manufactured in factories producing 100 MW_p per year (1.00 to 1.25 million m^2). This is an order of magnitude larger than the existing 5 and 10 MW_p/yr factories that have been built by USSC and BP Solarex and would be expected to yield major scale economies. The British Photovoltaic Association projects more than a 40% reduction in unit manufacturing costs ($/$W_p$) from scaling up PV thin-film factories from 10 to 100 MW_p/yr capacity (BPA, 1999).

The analysis reflects potential *cost cutting via marginal technological improvement* by focusing on 8%-efficient rigid, dual-junction modules and 10%-efficient flexible, triple-junction modules. These are higher than the 5% and 6.5% efficiencies that are routinely achievable with current BP Solarex and USSC modules, respectively. However, such efficiencies have been realized with dual- and triple-junction pilot modules (~ 0.1 to 0.4 m^2) fabricated in various laboratories, and these efficiencies are expected to be realizable in commercial products by fine-tuning existing

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[9] Table 8, p. 15, in EIA (2000); also available at http://www.eia.doe.gov/fuelrenewable.html.

[10] Both technologies use plasma enhanced chemical vapor deposition (PECVD) to deposit the semiconducting material onto a substrate coated with a transparent conducting oxide (BP Solarex) or a back reflecting contact (USSC). The final deposition is either a transparent front contact (USSC) or a reflecting back contact (BP Solarex). After deposition the USSC module is encapsulated by Tefzel (a plastic) whereas the BP Solarex module is encapsulated by a sheet of plain glass bonded to the substrate by EVA.

technologies through experience—i.e., without significant process change (Forest, 1997; Guha, 1996).

And finally the analysis takes into account potential *cost-cutting via learning-by-doing* because it is based on estimated "learned-out" costs for both module manufacturing and PV systems installation, including transactions costs such as for negotiating grid interconnections and building permits. The estimated module production costs presented here are what could be expected with a reasonably high degree of confidence in conjunction with the second 100 MW_p/yr module production facility built for a given technology (Stabinksy, 1998).

Module Production Costs

The economic modeling of 100 MW_p/yr module factories is based in part on discussions with R. Stabinsky (1998 and 2000), an engineer with extensive experience in designing, building, and operating a-Si:H semiconductor manufacturing facilities. Stabinsky foresees substantial improvements in capital productivity in scaling up to 100 MW_p/yr, when particular attention is given to system design opportunities relating to the large area PECVD reactors required. Such reactors are both the most costly pieces of equipment in a-Si:H module factories and the elements of the production line that limit throughput rate.[11] Stabinsky estimates that a PECVD reactor for a 25 MW_p/yr plant would cost no more than for a 10 MW_p/yr unit. Scale economies in the rest of the factory could be achieved by grouping four such reactors together while sharing the other equipment (e.g., for substrate handling, laser scribing of individual cells, module testing, and encapsulation) from a standard 25 MW_p/yr plant. All the equipment other than the PECVD reactors can accommodate higher module throughput with minor modification. Extra design costs would be incurred for the first such 100 MW_p/yr plant, but this analysis excludes these relatively minor costs since it focuses on the second such facility.[12]

Total production costs include direct manufacturing costs (see Tables 1 and 2), indirect costs, and capital and financing costs (see Table 2).

Direct manufacturing costs

The favorable economic outlook for thin-film PV systems arises in part from the low costs of the materials involved. Materials costs are estimated by calculating annual amounts of materials required for module production and estimating material prices under large-volume conditions

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[11] Assuming the plant is operated 6000 hours annually, the module throughput rate is 160–200 m^2 per hour (16 kW_p per hour) on average. The actual rate is slightly faster to account for maintenance downtime. The rate-limiting step is deposition of the *i*-layer (150–200 nm thick) in the *pin* junction, here assumed to be at a rate of 2 Å per second (over the deposition area of ~ 45–55 m^2 per run, which will be divided amongst the four PECVD reactors). Equipment modification of the *i*-layer deposition chambers might be necessary if this deposition rate cannot be attained.

[12] The present detailed estimate of capital cost scaling with output capacity to the 0.64 power (from Stabinsky) is consistent with standard cost engineering scale-up estimates for capital equipment in chemical plants--e.g., Jelen and Black (1983) give 0.6 as the mean value for the scale up exponent.

(see Table 1). The active photovoltaic materials make up a thin (~ 1 micron) layer deposited on the glass or stainless steel substrate and thus contribute only \$7.5 to \$8.1/m^2 to module cost (see Table 1). Substrate (glass or stainless steel) costs are low because these materials are inherently inexpensive. Although flexible stainless steel substrates (@ \$5.1/m^2) cost roughly the same as rigid TCO-coated glass[13] substrates (@ \$5.5/m^2), total materials costs are slightly less for flexible than for rigid modules (\$17.4 vs. \$19.6/m^2) because the latter require an extra piece of back glass for encapsulation. In addition, glass modules require some sort of frame (not included in Table 1), the cost of which is taken into account in calculating installation costs (see Table 4). Considering module efficiency differences (10% for-triple junction flexible modules vs. 8% for dual-junction rigid modules), materials cost differences are more pronounced (\$0.17/W_p for flexible vs. \$0.25/W_p for rigid). However, in both cases, overall materials costs are low, accounting for only 36-47% of direct manufacturing costs (see Table 1) and 12-17% of total module production costs (see Table 2).

Energy/utilities cost estimates are based on Lewis and Keoleian (1996) and Alsema (1997). Direct manufacturing labor costs are based on discussions with Stabinsky (1998)[14]. Estimates of other direct manufacturing costs (for supplies, spares, and factory maintenance and for plant overhead) are based on generic engineering cost estimation algorithms (see, for example, Jelen and Black, 1983). Other authors (e.g. Carlson and Wagner, 1993; Zweibel, 1999) have used similar approaches in arriving at comparable direct manufacturing cost estimates ~ \$50/m^2.

Indirect manufacturing cost

Indirect costs, which include expenses incurred for selling and marketing, general administrative costs, R&D costs, tax expenses, and contingencies, were estimated in accordance with general cost engineering principles (Jelen and Black, 1983). Indirect costs were found to be comparable to direct manufacturing costs (see Table 2). Although it is possible to reduce some of these indirect costs by a combination of good management, market conditions, and luck (such as reducing selling and marketing or contingencies expenses), it is unlikely that the indirect costs associated with module production and sales will be reduced much below the direct manufacturing cost levels.

Manufacturing capital and financing costs

For 100 MW_p/yr manufacturing facilities, initial capital outlays for installed equipment and the factory building, but excluding working capital, amount to about \$2.1 per W_p/yr of manufacturing capacity for flexible modules and \$1.7 per W_p/yr for rigid modules--considerably less than the current costs for 10 MW_p/yr production facilities (about \$4.0 per W_p/yr and \$3.2 per W_p/yr for the flexible and rigid options, respectively).

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[13] TCO = transparent conductive oxide.

[14] Assuming 3 shifts of 5-day weeks for 50 weeks per year (6000 hours of plant operation per year). It is assumed that scheduled maintenance occurs during the 6000 hours of plant operation. Labor costs include allowance for overtime for unscheduled maintenance as well.

The manufacture of triple-junction modules is more capital intensive than for double-junction modules primarily because it requires three more deposition chambers. In the USSC case still another vacuum chamber is added for the TCO deposition (so that in total USSC uses 4 more chambers than does Solarex).

It is assumed that factory construction would begin in 2005, that production would begin in 2007, and that the factory would be retired 10 years later[15]. Production costs are calculated assuming financing with 35% debt (6.5% real rate of interest[16]) and 65% equity, and for a 35% corporate income tax rate. Module prices are assumed to decline 5.5%/yr over the production cycle, with first-year prices set at levels that provide an overall 20% real internal rate of return on equity. Estimated annual cash flows for the flexible module factory are indicated in Table 3. Estimated capital and financing costs as well as levelized lifecycle module prices (calculated assuming a 14.5% discount rate, the weighted average real after-tax cost of capital for the corporation) are presented in Table 2 for both flexible and rigid modules.[17]

As shown in Table 2, capital and financing costs are comparable to or greater than direct manufacturing costs or indirect costs, even at the large production capacity levels considered in this assessment.

Projections of a-Si:H vs. x-Si module production costs

Estimated a-Si:H module prices for 2007, the first year of production for the 100 MW_p/yr factories modeled here, are \$1.9/W_p for rigid modules and \$2.0/W_p for flexible modules (see Table 3).These estimates are considerably less than the module price of \$3.0/W_p projected by the historical experience curve for PV in that year (down from about \$4.3/W_p at the end of 1999—see Figure 1), assuming a continuation of a business-as-usual growth rate (16%/yr) for global module sales. These substantially lower module prices are indicative of the economic gains expected to be realizable with a-Si:H and other thin-film technologies relative to crystalline silicon (x-Si) module prices.

The historical PV experience curve, determined largely by sales of x-Si technologies, cannot be used as a predictor for a-Si:H module prices, as illustrated by the above calculations of relative

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[15] The assumed lifetime of the envisioned PV module factory is based on interviews with an engineer who designed and ran such a facility (Stabinsky, 1998 and 2000). After ten years he estimated that significant refurbishing would be necessary to continue production. Any profits after a decade are relatively insignificant to the decision to build the facility because of discounting.

[16] Estimated from average nominal commercial loan rates since 1997 [see the Selected Current Interest Rates section of Selected Asset and Liability Price Tables from the U.S. Treasury's website (www.ots.treas.gov)] that are converted to real (inflation-corrected) rates using CPI inflation rates from the Bureau of Labor Statistics (www.bls.gov).

[17] Here (and in Table 3) it is assumed that all earnings are paid out as dividends to stockholders. In a real-world situation a large fraction of these earnings would probably be retained by the corporation for investments in new plants, in which case the stockholders would gain instead by appreciation of the capital stock.

module prices for 2007. Rather, it is likely that trends in a-Si:H module prices will be described by a new experience curve located below the historical curve. To illustrate, a hypothetical experience curve for a-Si:H is drawn in Figure 1 having the same slope (progress ratio of 82.6%) as the historical curve but passing through the projected year 2007 point with a (flexible module) price of $\$2.0/W_p$ and a cumulative a-Si:H production at that time of 430 MW_p.

Although the true experience curve for a-Si:H modules will be determined by market experience, comparing module buy-down cost estimates predicted by this hypothetical a-Si experience curve with a bottom-up calculation based on modeling 100 MW_p/yr production plants indicates the plausibility of this hypothetical curve.[18] As used here, the term "buy-down cost" is the total incremental expenditure on PV modules required to reduce the module price from its initial value (in $/Wp) to a target price roughly equivalent to the threshold at which PV becomes widely viable in fully commercial grid applications. It is assumed that all the PV sold during the buy-down process is worth the target price, with declining subsidies making up the difference between the current and target price.[19]

Consider buying down the cost of flexible a-Si:H modules from the estimated year 2007 price of $\$2.0/W_p$ to $\$1.2/W_p$,[20] the estimated price in the 10^{th} and final year of operation for a 100 MW_p/yr plant (see Table 3). As noted above, the $\$1.2/W_p$ figure is derived based on assumed 5.5% annual price reductions from the year 2007 price of $\$2.0/W_p$ which, in turn, was set to allow the factory to provide a 20% rate of return to shareholders over the entire production run. The buy-down cost predicted by the hypothetical learning curve (the triangular area under this experience curve in Figure 1) is \$0.55 billion—roughly twice the estimate for buying down the cost of modules produced over the 10-year lifecycle of the single 100 MW_p/yr plant described in Table 3. This top-down estimate is remarkably congruent with the bottom-up module price estimates presented here since the latter are based on a second “learned-out” 100 MW_p/yr factory following an initial plant at that scale. For comparison, the cost of buying down the cost of x-Si modules to $\$1.2/W_p$ from the projected 2007 price of $\$3.0/W_p$ is \$36 billion (see Figure 1).

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[18] Peterson (1997) and Cody and Tiedje (1997) both highlighted the potential for a-Si:H thin-film modules to outperform crystalline technologies during the coming decade in terms of cost, noting that module-scale a-Si:H technology had already achieved costs roughly competitive with crystalline technology in 1997, when cumulative production of a-Si:H modules (excluding small cells for calculators and other consumer electronic products) was less than 0.5% of the level for cumulative production of crystalline modules. Peterson’s illustrative analysis (using a hypothetical a-Si:H experience curve with an 85% progress ratio) suggested that a-Si:H modules would be able to achieve a price of \$1 per W_p by 2006 with a cumulative large module production level of about 400 MW_p. Figure 1, which includes a-Si:H production for small consumer electronic product cells as well as large modules, projects that a-Si:H prices will fall to about \$1 per W_p once total cumulative production reaches 5,100 MW_p. In contrast, the historical experience curve (see Figure 1) indicates that the price of x-Si modules will reach \$1 per W_p when the cumulative production volume reaches about 200,000 MW_p.

[19] This simplification allows a comparison of relative buy-down costs for thin-film and crystalline technologies, but it does not take into account important high-value niche markets.

[20] This final price is roughly consistent with the $\$1/W_p$ figure often listed as a target for widespread commercial viability of grid-connected PV.

Costs for Rooftop PV Systems

Estimated costs are presented in Table 4 for 4 kW_p PV systems[21] installed on rooftops of new US houses purchased by relatively affluent homebuyers. PV systems based on the use of both flexible and rigid a-Si:H modules are considered. These estimates take into account intrinsic cost advantages of home mortgage financing, opportunities for cost reduction as a result of field experience (learning-by-doing and marginal technological improvements), and installation cost differences inherent in the different characteristics of flexible and rigid modules. Although at the current time interconnection transaction costs are substantial,[22] scale economies will facilitate standard contracts with local utilities such that these costs become negligible and are covered by the standard contractor installation fee.

Two items left out of the cost calculations are home insurance coverage for PV systems and property taxes. Insurance costs are likely to be small or even zero and thus can be neglected.[23] Although property taxes could have a substantial impact on the economics of residential PV systems,[24] they are not taken into account here because such taxes are strongly biased against capital-intensive energy systems such as PV,[25] and it is assumed that government interest in advancing PV technology would lead to actions to level the playing field or at least neutralize

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[21] For US average insolation (1,868 $kWh/m^2/yr$) a 4 kW_p flexible module system (balance of system efficiency = 76.6%) would generate 5,720 kWh/yr—somewhat more than 1/2 the average US household electricity consumption rate in 1997 (10,600 kWh/yr). However, during periods of peak sunlight, the system will often produce more electricity than is needed onsite at that time, making it attractive to sell excess electricity into the grid (e.g, via net metering provisions).

[22] See, for instance, Alderfer et. al. (2000), for descriptions of interconnection costs.

[23] Typical annual home owner insurance rates range from about 0.1 to 0.3% of total replacement value. However, home owner insurance policies typically cover more than the estimated home value by a large margin, and annual premiums are often insensitive to changes in home value of the order of or less than $10,000 [~ 6% of the median sale price for new single-family homes ($152,500) sold in the United States in 1998], which would be approximately the installed cost of a 4 kW_p rooftop PV system (see Table 4). The insensitivity of home insurance rates to the presence of a PV system would be especially likely for higher income homeowners, the focus of the present analysis. Moreover, for these home purchasers, PV roofing would typically displace expensive high-end roofing options, so that the increase in home value from installing PV would tend to be less than $10,000. And finally, it should be noted that even if the presence of a PV system were to influence the insurance rate, the system replacement value is likely to decline sharply over the life of the system, in light of the expected strong downward trend in module and balance of system component prices, thus reducing the cost of insurance.

[24] Typical annual property tax rates average about 2% of assessed value. Taking into account a property tax at such a rate could raise the cost of residential PV electricity shown in Table 4 by as much as 35%. This figure would be mitigated to the extent that PV roofing displaces expensive conventional roofing (e.g. tiles or high-end shingles).

[25] In a head-to-head competition between PV and natural gas-based power generation, the property tax would have a far greater impact on the cost of electricity from PV (for which nearly all the cost is capital cost) than from natural gas (for which capital accounts for typically 30% of generation cost). Moreover, the dominant cost for natural gas electricity is for fuel, purchases of which are tax-expensed.

this bias.[26] On the basis of such considerations, eighteen states already exempt solar facilities from local property taxes.[27]

Because PV systems are capital-intensive, financing has a powerful effect on electricity generating cost. The home mortgage assumed here is the least-costly option for financing PV systems--both because of the low cost of money and because of the benefit of being able to deduct mortgage interest from income taxes. Mortgage interest rates (a real mortgage interest rate of 5.1% is assumed here[28]) are typically of the order of 1/3 of the average cost of capital for many business investments.[29] Moreover, being able to deduct mortgage interest from income for tax purposes can reduce lifecycle costs by more than 15% (see Table 4).[30]

Aside from the large potential cost reductions expected for module manufacture discussed above, improvements relating to the inverters required to convert the DC output of the modules into AC power are expected to lead to substantially reduced costs for PV power in the near term. Until recently, capital costs for inverters have been ~ $\$1/W_{ac}$ or more. However, the extensive field experience resulting from major government programs promoting rooftop PV installations in other countries (notably Japan and Germany) has led to sharp reductions in inverter costs, which, as of the summer of 2000, had reached $\$0.30/W_{ac}$ in Japan, the cost assumed in the present analysis (Miyamoto, 2000).

In addition, inverter improvements are expected to lead to major reductions in operation and maintenance (O&M) costs. O&M costs have been high for PV systems--e.g., Jennings *et al*. (1994 and 1996) measured O&M costs to be 0.6 to 5.0 ¢/kWh at PVUSA and 3.6 ¢/kWh on a 10 kW_p rooftop system. However, excluding power conditioning unit failures, other O&M costs were only 0.1 to 0.5 ¢/kWh. Maish *et al*. (1997) estimate that if the mean time between failures for power conditioning units can be increased to more than 20 years, O&M costs would be less than 1.0 ¢/kWh. A PVUSA site operator has suggested that an O&M cost of 0.5 to 1.0 ¢/kWh would be a realistic projection for the 2005 time frame (Whittaker, 1999). Here it is assumed that power conditioning units become sufficiently reliable in this period that O&M costs are reduced to $\$1.5/m^2$ per year—which is equivalent to ~ 1 ¢/kWh.

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[26] Property taxes, like all taxes, are transfer payments, not true costs. They inevitably cause economic inefficiency by distorting private decision making. Tax policy typically aims to minimize such distortions. Tax schemes that bias private decision making against investments that generate societal benefits (e.g. by displacing polluting technologies) should be avoided.

[27] See www-solar.mck.ncsu for more detailed information.

[28] Based on real average rates for 30-y fixed rate mortgages during the period 1990 through 1999 using data from the Bureau of Labor Statistics (www.hsh.bls.gov).

[29] The before-tax weighted average cost of capital for the PV module factory described in the previous section is 14.5%.

[30] Home mortgage interest deduction is a subsidy that is not likely to be phased out in the foreseeable future, as many have come to view it, in essence, as an entitlement. Including the rooftop PV system in mortgage financing is qualitatively no different from including the furnace, hot water heater, clothes washer and dryer, and stove, as is typically the case.

Estimates of the cost of installing PV roofing on new homes (Table 4) are based on conversations with both PV system installers and roofers, and include detailed considerations of all aspects of the installation process. The costs presented are for established PV system installers who offer their services in a competitive environment.

Installation costs are estimated to be about twice as large for rigid as for flexible modules (see Table 4). These differences reflect the fact that the flexible stainless steel modules have the potential to be far less costly to transport to the house site and install. Rooftop units based on glass are heavier, must be handled more carefully to prevent breakage, need a costly frame[31] and require more modules (and thus more labor operations and materials for interconnection) for a given installed capacity.[32]

Moreover, flexible modules can be rolled down over and fixed to an existing plywood base[33] by means of an appropriate adhesive and thereby displace shingles that would otherwise be needed--resulting in a modest credit for the cost of shingles avoided.[34] Such integration into residential roof structures is not likely for glass panels, which are instead assumed to be mounted above the roof, with a frame suitably designed to allow ventilation underneath. This ventilation permits cooler module operating conditions than is feasible with the flexible modules—resulting in a higher balance-of-system efficiency for rigid (80.5%) than for flexible (76.6%) modules.[35]

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[31] Anodized aluminum is the current frame material, although in the near future this might be replaced by cheaper reaction injection molded plastic, which is assumed here.

[32] Weight and maneuverability concerns constrain maximum rigid module size [2.4 m^2 is assumed here for rigid modules (based on the largest currently available rigid module) vs. a conservative estimate of 3 m^2 for flexible modules]. Combined with the lower efficiency of the rigid modules this implies that 25 rigid modules are required for a 4 kW_p system vs. 15 flexible modules.

[33] This plywood-based system should be achievable by modifying the USSC field-applied PV laminates for metal roofs (http://www.ovonic.com/unitedsolar/roofingsystempeelstick.html) so that it is possible to bond flexible modules to plywood (Heckeroth, 2000). Further product development is needed, but the system will likely involve first covering the plywood deck with a low-cost impermeable layer to which the flexible PV modules could be bonded (e.g. www.graceconstruction.com/roofing).

If bonding flexible modules to plywood proves unworkable, metal roofing would be necessary, for which the installation cost would be about $0.15/$W_p$ higher, even after accounting for the value of plywood displacement ($0.05/$W_p$) and the longer expected lifetime relative to conventional wood and shingles roofing ($0.10/Wp avoided replacement value in present value terms). This would nearly close the gap between installed costs for systems based on rigid vs. flexible modules.

[34] It is assumed that ordinary asphalt shingles are displaced by the rolled stainless steel modules.

[35] The overall system efficiency is rated module efficiency times the balance of system efficiency: 0.766*10 = 7.66% for flexible and 0.805*8 = 6.44% for rigid modules.

Total initial system costs for rooftop a-Si:H PV systems range from 1.4 times the module cost (W_{ac} basis) for flexible modules to 1.7 times the module cost for rigid units (see Table 4)[36]. Assuming mortgage financing and 25-y system lives, these costs can be translated into electricity generating costs for a given insolation. Under the net metering provision, PV systems would be economic from the consumer's perspective if the PV generation cost were less than the retail electricity rate. This condition can be met in areas with appropriate combinations of high insolation and high retail electricity rates. Two such areas are southern California (where the insolation is 6% higher than the US average and the retail rate is projected to be 10.4¢/kWh in 2007) and southern New York (where the insolation is 12% lower than the US average and the retail rate is projected to be 12.9 ¢/kWh in 2007)—see Table 4.

Although lifecycle costs are estimated here to be significantly less for flexible than for rigid modules, the rolled roofing on plywood approach is still under development and aesthetic considerations might tip the balance in favor of rigid modules for some consumers.[37]

Residential PV Development Strategies

It would be possible to install a million solar roofs on US residences by 2016 if a new 100 MW_p/yr module production facility were to go into operation every year beginning in 2007 and all of the output from these factories served the domestic residential market. As the analysis in the previous sections shows, current a-Si:H PV technology is a good candidate for some of the first of these plants. Future plants during this period might be based on alternative thin-film technologies, advanced a-Si:H technologies, or other promising low-cost PV options. In particular, factories for manufacturing cadmium telluride (CdTe) and copper indium diselenide (CIS) PV modules are under construction. Both of these potentially low-cost thin-film technologies offer the potential for higher energy conversion efficiencies than those offered by a-Si:H.

Developing a viable commercial market for rooftop PV will be easiest if initial activity is focused in a few regions to take advantage of localized scale economies. A single home building company that constructs an entire “solar subdivision,” for example, would be able to standardize its architectural and installation approach. Similarly, a regional cluster of such home builders could take advantage of specialized suppliers and pools of roofers and electricians skilled in solar installation.

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[36] Our finding that for residential PV systems module costs dominate total installed system costs, despite the low overall system efficiency, is contrary to the widely shared expectation that BOS costs will dominate as low cost levels are realized for low efficiency thin-film PV technologies.

[37] Also, rigid modules would tend to be favored for façade applications in commercial buildings, which often require architectural glass. The incremental cost of adding PV to glass walls would exclude the cost of the glass itself, module frames, delivery, or any non-wiring installation costs. Moreover, commercial-scale inverters will be considerably cheaper than the 4 kW_p models considered here for the residential PV roofing market. The potential for this market is considerable given the high value of PV electricity from South or West facing façades in urban areas with strong early afternoon peaks and high associated distributed benefits.

What is needed to facilitate such clustering of PV activity is a favorable combination of high electricity prices, good insolation, and strong housing construction markets. Having the highest residential electricity prices in the country and blessed with good insolation, Hawaii would seem to be an attractive target market. However, Hawaii accounts for less than 0.25% of single-family housing construction. Florida and Texas, also blessed with good insolation, together account for 1/6 of new residential construction but also enjoy low residential electricity prices and are thus not strong candidates for net metering strategies.

California and the greater New York region (New York + New Jersey + Connecticut) seem to have the most favorable combination of characteristics in the United States. Some 46% of the new single-family dwelling market in California (103,000 single family housing starts in 1999) would be adequate to absorb the output of two 100 MW_p/yr module production facilities, while 38% of the housing market in the greater New York region (62,000 housing starts in 1999) could absorb the output of one such plant.

A constraint on a California-based regional strategy is the fact that currently California caps net metering (for wind plus solar) at 0.1% of the 1996 peak demand. Even if net metering were allocated entirely to PV, this cap would limit the net metering benefit to less than half a year's output of a single 100 MW_p/yr plant.

In the long run, caps on net metering will be desirable; however, the time when caps will be needed is in the distant future even under the most ambitious PV development scenarios. This can be seen by considering in turn each of the three major reasons for considering net metering caps: electric grid stability concerns, PV power valuation concerns, and impacts on other rate payers.

Grid Reliability

Utilities have long been concerned about system reliability when large quantities of intermittent renewables are added to electricity grids. However, reliability of supply with intermittent renewables on the grid depends on what other generating technologies are used. It has been shown that where the grid system is powered mainly by nuclear or other inflexible baseload plants, reliability can become problematic; however, if backup is instead provided by hydropower or a mix of gas turbines and combined cycle facilities (which have rapid load-change-following capability), intermittent renewables can be accommodated on grids without loss of system reliability for renewables penetration ranging from 10 to 30 percent of total generation (Kelly and Weinberg, 1993). California electric grids are particularly well suited for incorporating large quantities of renewables, since hydropower accounted in 1998 for 26% of total generation, and essentially all new fossil energy plant construction is expected to be based on natural gas turbines and combined cycle plants.

Electricity Valuation

The second concern is that net metering is economically inefficient since the PV electricity is worth less to the utility than the retail electricity price implicit in net metering. Current electricity pricing is certainly consistent with this critique; however, some benefits, which may be difficult to quantify, can change this judgment. For example, distributed PV can often obviate or reduce the need for generating capacity since PV is highly coincident with air conditioning loads that often drive annual peak demand. Moreover, PV systems sited in distributed configurations near electricity users can lead to postponement of costly investments in transmission and distribution equipment. Furthermore, deployment can lead to increased system reliability (another distributed benefit). Finally, displacement of fossil fuel energy can yields significant environmental benefits. If electricity were properly priced to reflect all of these considerations, the argument that net metering is an inefficient subsidy might be undermined.

Ratepayer Impacts

The third concern is the welfare of electric ratepayers—especially those whose rates go up as a result of net metering but who do not benefit directly from a PV roofing system. One response to this concern is that those who do not enjoy the direct economic benefits of PV net metering still enjoy the environmental benefits associated with launching this technology in the market. A second response is that the penalty to non-PV users is quite modest even in extreme circumstances. The penalty is likely to be the most severe in California if all of the PV output from the first two 100 MW_p/yr plants is used for residential applications in that state. The maximum penalty would occur near the end of the production runs of these plants, when residential PV would contribute about 1% of electricity consumed in the state, and net metering would lead to only about a 0.12% increase in California electricity rates for each 1 ¢/kWh of implicit subsidy. Moreover, this subsidy is likely to be of the order of 1 ¢/kWh or less with proper electricity pricing. [A forthcoming paper (Duke et al., in progress) discusses the two topics of proper valuation of PV electricity and total consumer cost in more detail.]

A Closer Look at the Policy Context

The combination of an RPS and net metering may make it possible to successfully launch a profitable PV industry for exploiting grid-connected market applications without the need for large subsidies.

In principle, the RPS will guarantee a sufficiently large PV market to give firms with low-cost modules the confidence to bear the risks of building large (~ 100 MW_p/yr) module factories that offer substantial scale economies. This sizable market in turn should make it feasible to realize rapidly declining PV costs both in the factory and in the field (as a result of learning-by-doing and exploiting opportunities for making marginal technological improvements). An especially appealing feature of an RPS is that, because it uses the market to choose the least-costly options, subsidies required as commercialization incentives are relatively modest. For example, as was noted above, the cost of buying down the cost of a-Si:H modules to a \$1.2/W_p price level is estimated to be only about 2% of the buy-down cost for x-Si modules. An RPS should tend to encourage thin-film module use to the extent that faster cost reduction progress is realized for this technology class. Moreover, RPS subsidies will decline and ultimately self-extinguish as costs come down.

The analysis presented in the previous section did not take into account the value of the renewable energy credits that would be associated with an RPS. Such credits would provide additional incentives for overcoming barriers to initial market development, including the extra costs of building and operating the very first 100 MW_p/yr plant, relatively high initial equipment prices, customer ignorance of the potential for PV roofing, and risk-aversion on the part of home builders and buyers.

As shown, net metering makes PV from scaled-up a-Si:H factories profitable to consumers in regions that have the appropriate mix of high insolation and high retail electricity rates. Some have argued that there is a subsidy implicit in the net metering arrangement, which would ultimately require higher electric rates for consumers. As noted above, however, a companion paper (Duke et al., in progress) argues that with proper energy pricing the subsidy implicit in net metering will be low and might even be zero in many cases.

Are additional incentives other than those implicit in an RPS and net metering needed to successfully launch PV technology in grid-connected markets? As noted above, one important piece of reform is taxation policy that provides a level playing field for competing technologies—giving particular attention to policies such as property taxes that are biased against PV and other capital-intensive energy technologies. The exemptions already in place in eighteen states are a promising precedent in this regard.

It is, however, plausible that the "guarantee" offered by the RPS to give investors the confidence to build large module factories is no guarantee at all. If, for example, the RPS were to allow interregional trading of renewable energy credits, it might turn out that essentially the entire RPS obligation could be satisfied at the least cost by building large wind farms in the wind-resource-rich Great Plains and selling the associated renewable energy credits to electricity providers in other parts of the country. If it appeared that this would happen, a pure RPS would not be able to satisfy the desirable objective of buying down costs for a portfolio of renewable energy technologies.

Various options might be considered for modifying an RPS in ways that would ensure that its benefits could be shared across a portfolio of technological options that would include PV. One strategy would disallow interregional trading of renewable energy credits initially, until several alternative renewable technologies achieve substantial market penetration levels. This approach would, however, undermine the efficient resource allocation feature of the RPS. An alternative approach would be to create separate RPS tranches for alternative renewable energy technologies; but this would require that the government attempt to pick winners. Excessive government micro-management could be avoided by instead specifying that no one technology (e.g., wind) be allowed more than a certain fixed share of the full RPS obligation. For immature technologies such as PV even a small window opened up in this manner could offer a powerful incentive to producers. A million roofs target would require that PV account for less than 0.4% of national electricity supply by 2015—a modest figure in relation to likely state and federal RPS levels such as the 7.5% RPS mandate for 2010-2015 in the Clinton Administration's proposed Comprehensive Electricity Competition Act.

Although PV technology has reached a point in its evolution where it can begin to contribute in grid-connected applications, PV will not become a significant contributor to electricity supplies until the very distant future unless ways can found to sustain market growth rates of the order of 35-40% per year for a period on the order of a couple of decades. If the 38% growth rate implicit in the million roofs target for the period 2007-2016 could be sustained until 2025, PV could by then provide about 3% of total US electricity supplies and be considered fully "launched" in the market. Such sustained growth rates are not unprecedented for new energy technologies: between 1957 and 1977, installed nuclear capacity in the United States and the world grew at average rates of 36% and 37%, respectively (Williams and Terzian, 1993). However, continuing incentives may well be needed to sustain rapid growth rates for such a long period.

Pricing of electricity to reflect properly its time-of-use value, distributed benefits, and environmental costs not now included in market prices could provide the needed incentive for sustaining accelerated market development over a period of decades. Alternatively, if efficient electricity pricing proves to be politically unviable, a continuation of net metering even long after phase out of the RPS might be considered instead—an option that would be especially attractive if net metering turns out to be a relatively good surrogate for efficient pricing (Duke et al., in progress).

Realization of sustained accelerated PV development will also require an expanded PV R&D effort—in three areas: fundamental and strategic R&D, product development, and end-user-oriented R&D, with expanded investments made by both the public and the private sectors. PV markets will be much broader and can grow much more quickly if new technology makes it possible to accelerate the pace of cost reduction. There is much room for improving PV module efficiencies. Some analyses estimate that thin-film PV module efficiencies double those considered in the present paper may well be achievable in the period 2020-2030 (EPRI/OUT, 1997).

But public-sector support for PV R&D has been lagging. The average level of US DOE investment in PV R&D during 1997-2000 was $65 million per year, down 22% relative to the average rate of investment for the previous three years, despite a major recommendation in 1997 by the Energy R&D Panel of the President's Committee of Advisors on Science and Technology to ramp the federal budget up to more than double the 1997 level over a five-year period (PCAST Energy R&D Panel, 1997). Moreover, Kammen and Margolis (1999) have documented a sharp drop in private-sector energy R&D. Both of these trends must be reversed if there is to be a sustained rapid rate of PV industrial expansion.

The RPS/net metering strategy advanced here would be directly helpful in expanding private-sector R&D. As the industry expands rapidly in response to these incentives, total internal funding available for R&D investments would grow exponentially. For the accelerated development (million roofs) scenario outlined above, US PV production by 2010 would be over 700 MW_p/yr, compared to less than 50 MW_p/yr in 1998, resulting in R&D expenditures of the order of $70 million/yr[38]—three to four times the rate of private-sector R&D investment in the

[38] Assuming that R&D expenditures are 6% of sales (see Table 2), that the module price is $1.69/$W_p$ in 2010 (see Table 3), and that the US PV production in 2010 is 715 MW_p/yr.

late 1990s. These R&D expenditures would be committed mainly to developmental and product improvement activities.

With such large private-sector expenditures on near-term R&D, expanded public-sector R&D[39] could emphasize strategic, longer-term research, to enhance the prospects for a continuing flow of PV innovations into the market. Such strategic long-term R&D is where federal funding is needed most, given the risk that the results of private investments will spill over to competitors during the extended period typically required to commercialize fundamental scientific innovations.

Ensuring effective investment in end-user oriented R&D may require the development of a new institution modeled after the Electric Power Research Institute, but drawing its membership from electric service providers (or any remaining utilities) and with a narrow mandate to lower the cost of complying with RPS/net metering legislation. This approach would ensure that the private companies most familiar with the process of marketing and successfully installing and operating PV roofing would be in charge of directing R&D funds to achieve these public benefits as quickly as possible. The industry could theoretically fund such an institution through voluntary contributions but it would be essential to have a stable mandate and funding to avoid disrupting R&D efforts.

This argues for using a portion of revenues from systems benefits charges (small non-bypassable wires charges on all providers of electricity) that are increasingly being put in place to support various energy-related public interest activities in the emerging more competitive electric industry. Already fourteen US states have introduced system benefits charges, and the proposed Comprehensive Electricity Competition Act has provisions for a federal systems benefits charge.

Conclusion

This bottom-up analysis has shown that a-Si:H module vendors would be able to earn a substantial return (20% IRR) on 100MW$_p$/year a-Si:H module manufacturing facilities by selling at an initial price of \$2.0/W$_p$, falling to \$1.2/W$_p$ by 2016. Moreover, residential PV systems using modules in this price range would be attractive investments for home buyers in regions characterized by suitable combinations of high electricity rates and adequate insolation. The analysis also underscores the importance of emphasizing market development in regions that combine these attributes with strong housing markets (e.g. California and the greater New York region).

A combined policy of net metering and an RPS has the potential to catalyze this market and encourage the installation of PV systems on one million residential rooftops by the middle of the next decade, at which time the RPS could be phased out. However, even then policies would be needed that can sustain a domestic PV market growth rate of 35-40% per year for up to two

[39] For FY 97, US federal support for PV R&D amounted to $60 million, 49% of which was for strategic R&D, 19% was for technology development, and 32% was for systems engineering and applications.

decades in order to enable PV to provide as much as 3% of total electricity by 2025. Sustaining such a high rate of market growth will require a combination of efficient electricity pricing and substantially expanded private and public investments in PV R&D. Finally, an extension of net metering well beyond the phase out of an RPS might prove useful if efficient pricing that incorporates both localized distributed benefits and environmental costs proves too difficult to implement.

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Table 1: Materials Costs and Other Direct Manufacturing Costs[a]				
	Flexible (*stainless steel*)		**R**igid (*glass*)	
Materials	$/m^2$	$/W_p$	$/m^2$	$/W_p$
Substrate (F: stainless steel; R: TCO glass)	5.11	0.05	5.50	0.07
Plain glass for encapsulation (R only)	-	-	2.89	0.04
Transparent conducting oxides (F: ITO + ZnO; R: ZnO)	2.14	0.02	1.71	0.02
Encapsulant (F: Tefzel; R: EVA)	2.05	0.02	2.00	0.03
Silane (includes disilane for F)[b,d]	0.72	0.01	0.48	0.01
Germane[c,d]	7.07	0.07	6.74	0.08
Miscellaneous	0.33	0.00	0.32	0.00
Subtotal	17.42	0.17	19.64	0.25
Energy and utilities[e]	2.60	0.03	2.60	0.03
Direct manufacturing labor (DML)[f]	4.68	0.05	3.75	0.05
Supplies, spares, and factory maintenance (S,S, and FM)[g]	13.21	0.13	8.64	0.11
Plant overhead[h]	10.73	0.11	7.43	0.09
Total direct manufacturing cost	48.64	0.49	42.06	0.53

Notes for Table 1:

a. For this table it is assumed that the factory is operated at a full usable output rate of 100 MW_p/yr.
b. F: 3.7 g silane/m^2 @ $0.13/g + 0.8 g disilane/m^2 @ $0.30/g; R: 3.7 g silane/m^2.
c. F: 2.0 g germane/m^2 @ $3.50/g; R: 1.9 g germane/m^2.
d. The gas utilization rate for both silane and germane is assumed to be 25%.
e. Electricity required = 57 kWh/m^2, assuming an average industrial rate = 4.6 ¢/kWh.
f. 100 employees @ $38,840/yr + 10 managers @ $80,000/yr, full compensation costs. Based on three shift (6000 hours of plant operation per year), which includes labor costs for scheduled maintenance and allows for some unscheduled maintenance. [Stabinsky (1998) estimates that only 80 employees are needed for plant operation and scheduled maintenance, so that 20 employee-equivalents would be available for unscheduled maintenance, e.g. paying employees overtime or hiring part-time employees.].
g. 7%/yr of initial capital outlay [$15 million for building + $173.7 million, F, or $139.2 million, R, for installed equipment].
h. 60% of DML + S,S, and FM.

Table 2: Components of Levelized Lifecycle Module Sales Price[a] (*$/W_p*)		
	Flexible	**R**igid
Direct Manufacturing Costs		
Materials	$0.19	$0.26
Energy and utilities	$0.03	$0.03
Direct manufacturing labor	$0.05	$0.05
Supplies, spares, and factory maintenance	$0.11	$0.10
Plant overhead	$0.14	$0.11
Subtotal	$0.51	$0.56
Indirect Costs		
Selling and marketing[b]	$0.08	$0.08
General administrative[c]	$0.13	$0.13
Product development/essential R&D[d]	$0.12	$0.11
Tax expense[e]	$0.14	$0.12
Contingencies[f]	$0.04	$0.04
Subtotal	$0.52	$0.48
Capital and Financing [g]		
Building and Equipment[h]	$0.48	$0.39
Capitalized indirect costs[I]	$0.13	$0.12
Subtotal	$0.62	$0.52
Total	1.66[j]	1.55

Notes for Table 2:

a. This table presents the levelized lifecycle sales price P_{avg} disaggregated by cost component. If the product were sold at this price each year the IRR on the plant's equity investment would be 20%. The costs are disaggregated in proportion to their discounted present value compared with the discounted value of the total cost. Direct manufacturing costs differ slightly from those in Table 1 because here it is assumed that 5% of output is off-spec and thus lost, and because costs are levelized over the plant life (assuming a 14.5% real discount rate), taking into account reduced production during ramp-up (first 2 years of production--see Table 3).
b. 5% of sales revenue.
c. 7% of sales revenue.
d. 6% of sales revenue.
e. For a 35% corporate income tax rate.
f. 5% of total direct and indirect costs.
g. Financing by 35% debt and 65% equity. Debt at 6.5% interest, 10-y term. Equity at a 20% internal rate of return.
h. Initial capital outlays: $15 million for building + $173.7 million (F) or $139.2 million (R) for installed equipment. Two-year factory construction period.
i. Prior to factory completion, product development, G&A, and contingencies still accrue requiring some working capital.
j. This is slightly higher than USSC's own estimates for a 100MW$_p$/yr plant of $1.50/W$_p$ (personal communication Jeff Yang, 8 December 1999).

Table 3: Cash Flow Projections for Flexible (Triple-Junction, Steel Substrate) Case												
Year	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
Module price[a] (*$/W$_p$*)	2.24	2.11	2.00	1.89	1.79	1.69	1.60	1.51	1.43	1.35	1.28	1.21
Module sales (*MW$_p$*)	0	0	41	83	95	95	95	95	95	95	95	95
Cash flow (*$10^6/yr*)												
Revenues from module sales	0	0	82	156	170	161	152	143	136	128	121	115
Direct manufacturing cost	0	0	(20)	(40)	(49)	(49)	(49)	(49)	(49)	(49)	(49)	(49)
Indirect manufacturing cost	(28)	(28)	(28)	(33)	(35)	(33)	(31)	(30)	(28)	(27)	(25)	(24)
Outlays for building and installed equipment[b]	(94)	(94)	0	0	0	0	0	0	0	0	0	8
Loan capital infusion	43	43	-	-	-	-	-	-	-	-	-	-
Debt repayments (principal + interest)	-	(3)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)	(12)
Tax expenses	-	-	-	-	(10)	(22)	(20)	(18)	(16)	(14)	(12)	(13)
Net earnings (dividend payments), 20% IRR	(79)	(82)	21	71	65	45	40	36	31	27	23	24

<u>Notes for Table 3</u>:

a. The module price is assumed to decline 5.5% per year over the project life. The initial module price (for the year 2005) is set at a level that gives rise to a 20% IRR. For the rigid module case (dual junction, glass substrate) the module price in 2005 would be $2.09/W$_p$.

b. At the end of 2016 salvage values are assumed to be $7.5 million for the building and zero for equipment.

Table 4: Lifecycle Costs for 4 kW_p PV Systems on Rooftops of New Residences

	Flexible[a] (*stainless steel*)			**R**igid[b] (*glass*)		
	Total cost (*$*)	Specific cost (*$/W*)	Electricity generating cost[c] (*¢/kWh*)	Total cost (*$*)	Specific cost (*$/W*)	Electricity generating cost[c] (*¢/kWh*)
Costs, DC output basis						
Module price	6,640	1.66		6,200	1.55	
Installation cost						
Materials[d]	(65)	(0.02)		263	0.07	
Module integration[e]	153	0.04		492	0.12	
Delivery & taxes[f]	162	0.04		456	0.11	
Labor[g]	1,375	0.34		1,954	0.49	
Subtotal, installation	1,640	0.41		3,164	0.79	
Rooftop O&M[h]	840	0.21		1,040	0.26	
Mortgage interest deduction[i]	(1,800)	(0.45)		(1,880)	(0.47)	
Subtotal, DC output basis	7,320	1.82		8,520	2.13	
Subtotal, AC output basis[j]	7,320	2.37		8,520	2.65	
Power conditioning cost[k]	919	0.30		966	0.30	
Total cost, AC output basis						
Southern CA[l]	8,240	2.67	9.4	9,490	2.95	10.3
Southern NY[l]	8,240	2.67	11.6	9,490	2.95	12.9
Northern IL[l]	8,240	2.67	11.9	9,490	2.95	13.2

Notes for Table 4:

a. 40 m^2 of total module area (3 m^2 per module).
b. 50 m^2 of total module area (2.43 m^2 per module).
c. For a 5.1% real discount rate and a 25-y PV system life, the monthly levelized charge rate is 0.59%.
d. F: $150 gross materials cost (much less than for R because fewer modules so fewer connectors, less wiring needed) - $215 shingles credit.
e. R: 85% of module integration cost accounted for by frame to protect glass edges; molded plastic frame @ ~ $17 per module.
f. R modules are ~ 2X as heavy (~ 345 kg for 50 m^2) as F modules and cost much more to ship because of care needed to prevent breakage.
g. Easier installation for F (modules roll down onto existing plywood base) reduces contractor markup (F: $0.26/$W_p$; R: $0.35/$W_p$), other labor costs (F: $338; R: $570).
h. Present value of annual O&M cost of $1.5/$m^2$, for 25-y system life, 5.1% real residential discount rate.
i. For 20% down payment, a 25-year mortgage at 5.1% interest (real), and a 33.5% tax bracket (high-income homeowner assumed).
j. For system efficiencies of: 76.6% for F (flush on roof) and 80.5% for R (elevated above roof); lower operating temperatures for R.
k. Personal communications of the authors with Masao Miyamoto of Sanyo 2/24/00.
l. For a daily average insolation of 5.6, 4.5, and 4.4 kWh/m^2 in southern CA, southern NY, and northern IL, respectively.

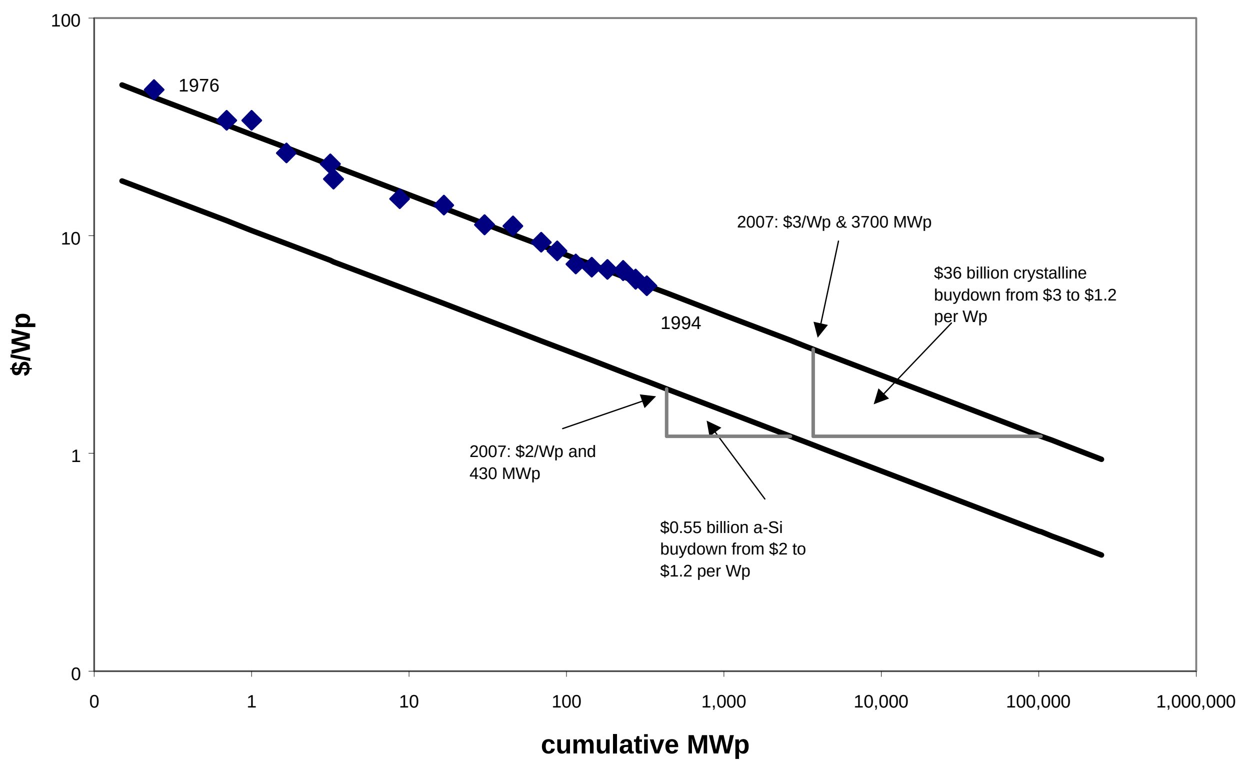

Figure 1. Costs of "buying down" to $1.2 per W_p prices for crystalline silicon and a-Si:H modules from their projected year 2007 price levels.

This figure is based on the historical experience curve for crystalline technologies (EPRI/OUT, 1997) and an a-Si:H curve assumed to have the same progress ratio. Buy-down is defined here as the total incremental expenditure required to reduce module prices from their initial values to the $1.2 per W_p target price. [For other PV experience curve analyses see Cody and Tiedje (1992; 1997) and Williams and Terzian (1993).]

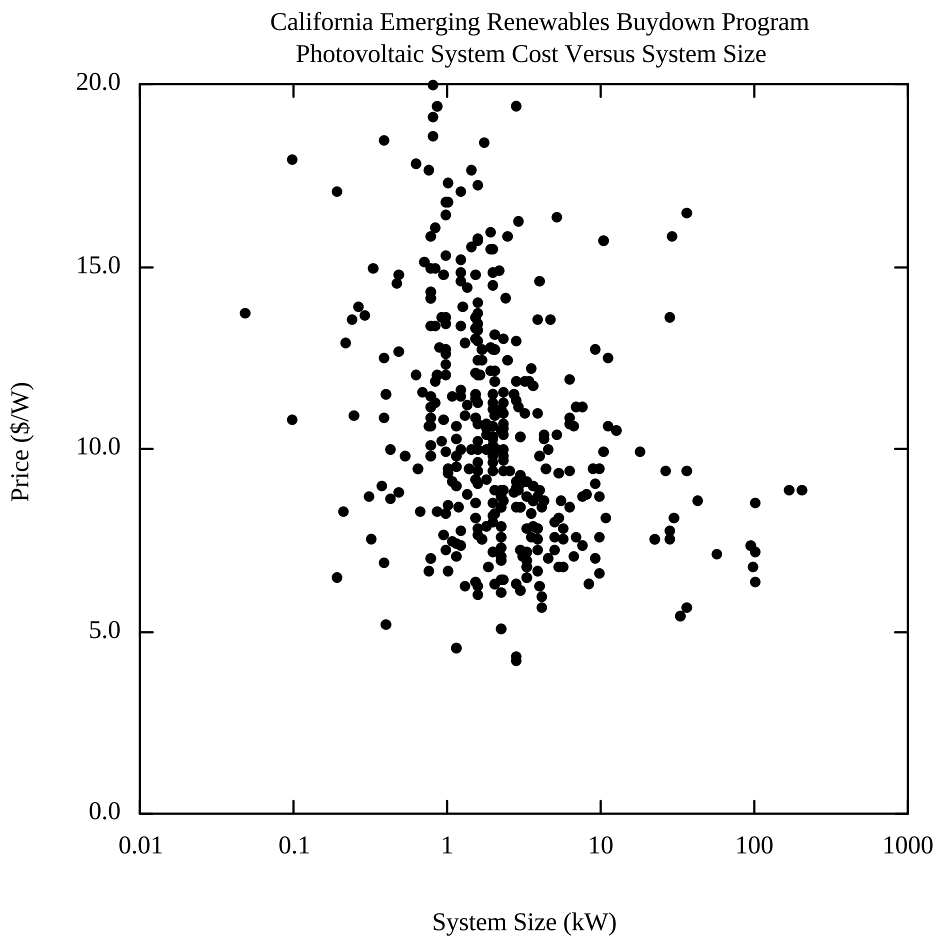

Figure 2. Residential PV system price vs. size for the Emerging Renewables Program of the California Energy Commission

Prices are shown for the 351 systems subsidized during the first two years (March 1998 through June 2000) under this buy-down program, for which funds were provided from California's Systems Benefits Charge levied as a non-bypassable wires charge on retail electricity providers in California. Customers of California's three investor-owned utilities are eligible for the subsidy on a first-come, first-served basis, except that 60% of the total available funding must be used to support small systems. Initially the subsidy amounted to the lesser of $3/W or 50% of the total system price; the amount of subsidy per unit has declined as remaining available funds have been reduced. From Schwent and Starrs, 1998, p. 7, updated by Sandy Miller (personal communication, 6 July 2000).